Technical Work Group
of the Imperial Valley Study Group
Amended Minutes of August 10, 2005 Meeting

In attendance: David Barajas, Jorge Barrientos, Mark Etherton, IID; John Kyei, CA ISO; Robert Jackson, Abbas Abed, SDG&E; Phil Leung, SCE; Dale Stevens, CalEnergy; Dave Olsen, CEERT/CEC; Jim Kritikson, for Coral Power; Ron Davis, consultant to CEC; José Santamaria, CFE. Ralph Hitchcock, independent consultant, also attended. The meeting convened at 9:20 AM and adjourned at 3:05 PM. Minutes were recorded by Dave Olsen.

Minutes of the August 4, 2005 TWG meeting were approved, as amended.

Production Simulations: We reviewed John's production simulations of Alternatives 2, 2a and 3b, along with the benchmark case. He used the WECC-approved 2008 base case, updated for 2010 loads and resources for APS, CFE, IID, LADWP, SCE, SDG&E. Input data/assumptions include: 1-in-10 summer temperatures; average generator heat rates; generator start-up/shut down costs and forced outage rates, average hydro conditions, historical wind output, gas prices @$4/MMBtu. Current gas prices are in the $9 range across the WECC, and futures contracts are above $10. But because the objective of the simulations was to help us choose among alternatives relative to each other, rather than to justify an investment decision, John concluded that the level of gas price would not affect the relative results. For the same reason, he did not input the gas prices at different WECC hubs. Variable O&M costs for the geothermal generators are included. ABB Gridview applies Monte Carlo logic (one iteration) to model generation outages. (Transmission forced outage is not modeled). Gridview outputs are hourly production costs and LMPs at each WECC node, the hours of congestion on major paths, and transmission losses.

The benchmark case is the pre-project situation: it does not include the 2,200 MW of new geothermal generation nor any new transmission. Relative to the benchmark case, all of the study alternatives reduce (total WECC) production cost, by roughly $500 million/year. This is the difference in what it costs generators to serve load (mainly savings in fuel and operating costs). Congestion decreases, relative to the benchmark, because the Alternatives add the 500 kV line and upgrades of the IID system. Transmission losses increase, because more remote generation (geothermal power in the Imperial Valley) is replacing in-basin energy.

It was agreed that the TWG report should emphasize that these production simulation results—the comparison of the benchmark case against the study Alternatives—cannot be used as a basis for investment decisions. Readers unfamiliar with production cost modeling could conclude that the IVSG transmission alternatives reduce production costs by $500 million/year. While adding renewables generation is in fact likely to reduce production cost, the simulations performed to date were not designed to produce a reliable forecast of the potential savings. To be accurate, such a comparison would have to model, among other things, a range of hydro conditions, regional differences in gas prices, and a current forecast of gas prices, along with the cost of the new generation and new transmission. Preparing this comparison involves substantially more work; it is doubtful that it could be completed in time for the IVSG final report due September 30. It was further agreed that the description of the production simulations in the IVSG report should point out that the loadings shown in the flow duration curves do not include some upgrades that may be needed for reliability (outage contingency) purposes.

To demonstrate the value of the proposed transmission, the ISO was requested to complete one additional case showing the addition of the 2,200 MW of new geothermal generation with no transmission upgrades added. Olsen was directed to talk with John Kyei about the possibility of performing production simulations of the new Phases 1-3 that would indicate the benefit to consumers of the complete 2,200 MW development.

Phase 1a Power Flow: SCE reported that for Phase 1-Alternative A (Path 42 upgrade), the Light Autumn case would not solve with 1,000 MW of Imperial Valley generation added. (SDG&E found the same result). The Phase 1a /Light Autumn case did solve with 645 MW of IV generation added, except for an outage on the Devers-Valley line. Phil will identify mitigation for that contingency. He hasn't run the Heavy Summer case yet, but thinks that it will solve with the 1,000 MW added.

SCE's study approach is to fill Devers to its rated capacity and then add new generation to see the upgrades needed to make that generation deliverable. SCE included one new 800 MW generation project at Devers in the LA case runs. There are actually two 800 MW generation projects proposed at Devers (one has its SIS already completed). It was agreed that if the 800 MW project with a completed SIS requires transmission upgrades in order to connect, then those upgrades should be included in our IVSG Phase 1a power flow cases, because those upgrades could make more IV generation deliverable at Devers.

We also agreed the TWG report should note that there are generation projects already in the ISO queue that will thus have higher interconnection priority than IV geothermal generation.

If 645 MW of IV generation is deliverable in Light Autumn but 1,000 MW is not, it would be useful to know how much IV generation could be deliverable at Devers without the major mitigations that appear to be necessary to deliver 1,000 MW. SDG&E reported that when it ran the Phase 1a LA case with all the SCE capacitors turned on, 845 MW flowed to Devers.

SCE agreed to re-run the case to identify mitigations that would make 1,000 MW of Imperial Valley generation deliverable at Devers under Light Autumn conditions. Phil will also run the Phase 1a HS case, at both 645 MW and 1,000 MW incremental IV generation. He will send results **by COB August 17**.

Phase 1b Power Flow: Robert reported that overloads on the SDG&E system in Phase 1-Alternative b are solved by the proposed Silvergate substation. This substation has a 2008 in-service date, but was not included in our base case. SDG&E will re-run the cases with Silvergate included. SDG&E also noticed that IID's Midway-Highline overloads, with 645 MW generation added in the LA case, and with 1,000 MW added in the HS case (in the event of a North Gila-IV outage).

In the Phase 1 (2010) Light Autumn case, SDG&E could not get 1,000 MW of IV generation to flow into San Diego, even after turning off all generation in San Diego, which is not a reasonable assumption; but 645 MW works without problems. SDG&E concludes that scheduling 1,000 MW of IV generation to SDG&E <u>and</u> 1,000 MW to SCE <u>in 2010</u> is not reasonable, given the forecasted load level that year. However, if Phase 1 has to accommodate a full 1,000 MW of new IV generation, it appears that two-thirds or more could be scheduled to SDG&E and the remainder to SCE.

The power flow runs of our 2,200 MW export alternatives, which we completed in April, showed that 1,000 MW was deliverable to SDG&E, even in Light Autumn conditions. The difference is that these runs included the Banister-San Felipe and the El Centro-Avenue 58 upgrades of the IID system. Exporting the full 2,200 MW of IV generation thus appears to require the Banister-San Felipe and El Centro-Banister upgrades.

New Phasing Proposal: After considering the results of the power flows and the production simulations, we recommend to the IVSG Steering Committee that development plan should be approached in these phases:

	Year	New Generation	Cumulative	Routing/Upgrades
Phase 1	2010	645 MW	645 MW	1b (Highline-El Centro-IV-SD Central 500 kV)
Phase 2	2016	645 MW	1,290 MW	1b + El Centro-Banister-San Felipe
Phase 3	2020	910 MW	2,200 MW	IV-SD Central-SerVal +P42

We note that the IID Coachella-Ramon upgrade should be considered a pre-project upgrade (i.e., before Phase 1), as it is required to serve Coachella Valley load rather than for the export of renewables generation from the Imperial Valley. The issue of who will pay for the Coachella-Ramon upgrade remains open.

For Phase 2, we must determine whether or not any Path 42 upgrade is required. **IID agreed to perform this study**; to do so, it will increase IID load in 2016 by 11% over 2010 levels. We also must determine whether or not the connection between the SDG&E and SCE systems is required (as it is in Phase 3).

No further studies are needed for Phase 3.

José Santamaria will check to make sure that Phases 1-3 do not cause unacceptable loop flow on the CFE system.

Conceptual Cost Estimates: IID will provide cost estimates for the upgrades of its system in Phases 1 and 2, including geothermal collector substation at the Salton Sea, and including environmental study/permitting costs and ROW costs.

SCE will provide conceptual cost estimates for its share of any Path 42 upgrades (Mirage-Devers), plus any network upgrades West of Devers, also including permitting and ROW costs.

SDG&E is preparing cost estimates for its 500 kV project, but will not be able to release them before the IVSG report is filed September 30. The IVSG report may thus have to refer to a future CPCN filing by SDG&E for information on the costs of that component of the IVSG development plan.

TWG Final Report: We agreed that the report must emphasize the need for flexibility in how the phases are defined and triggered. If geothermal (and/or solar) power is sold to APS or LADWP, this could require upgrades of different facilities on the IID system than are included in our recommended Phases 1-3. To the extent that such sales reduce flows to CAISO delivery points, they could also defer the Phase 1-3 upgrades.

We also agreed to emphasize that generating projects already in the ISO (or SCE) queues have interconnection priority over new Imperial Valley projects; this could delay the on-line dates of IV renewables generation. The system impact of any projects that connect before new IV generation will have to be taken into account when the IV projects apply for interconnection.

We agreed to eliminate Chapter 4. Instead, a summary of the impact of the IV generation on the flows at major regional buses will be included in a sub-section of Chapter 3.

> **Writing Assignments Due**: We reviewed the sections of Chapter 3 that each person will write. Drafts of these sections are to be circulated to the TWG by **August 23**. This will give us a full day to review them before we discuss them during our next meeting August 25.

Agenda for the next meeting, August 24:

1. Approve minutes of our August 10, 2005 meeting.
2. Review new production simulations.
3. Final sign-off on power flow results for Phases 1, 2 and 3.
    - Review SCE mitigations for Phase 1-Alternative A Light Autumn case; and confirm Heavy Summer results.
    - SDG&E confirm Phase 1-Alternative B does not overload with Silvergate sub included.
    - Path 42 upgrade required for Phase 2? (IID to report).
    - SerVal connection required for Phase 3? (SDG&E to report).
    - Confirm no loop flow on CFE system.
4. Review all draft sections of Chapter 3 of the TWG report.
5. Review conceptual cost estimates (IID; SCE; SDG&E to provide language describing availability of cost estimates for the 500 kV project).
6. Identify maps and diagrams to be included, and assign people to provide them.
7. Agree on the content and structure of the appendices which will include the results of our technical studies.

Next Meetings/Key Dates:

August 25, 2:00-4:00 PM, phone meeting: 1-800-966-1573, passcode #754696. (For Mexico/CFE, let Merrie Lamb know if you will participate and she will have the operator phone you to connect).

September 1, 2:00-4:00 PM, phone meeting. US toll-free: 1-877-842-5648; passcode #737571. For Mexico/CFE, same procedure as for August 25 call.

September 12: Draft of the IVSG report circulated for comment (to STEP, SDG&E and IVSG lists).

September 15, 1:00-5:00 PM. Full Study Group meeting, to take comment on our draft report. Location: SANDAG, 401 B Street, 8th Floor, San Diego.